6. SYSTEMS ANALYSIS

The purpose of the systems analysis effort in this short term study is to identify system concepts which would show the typical resource, economic, and environmental impact of implementing hydrogen in selected sectors of the energy system. The concepts identified are listed below.

1. The use of hydrogen, generated with available off-peak electricity, as a clean fuel in the transportation sector (auto, diesel, or aircraft).

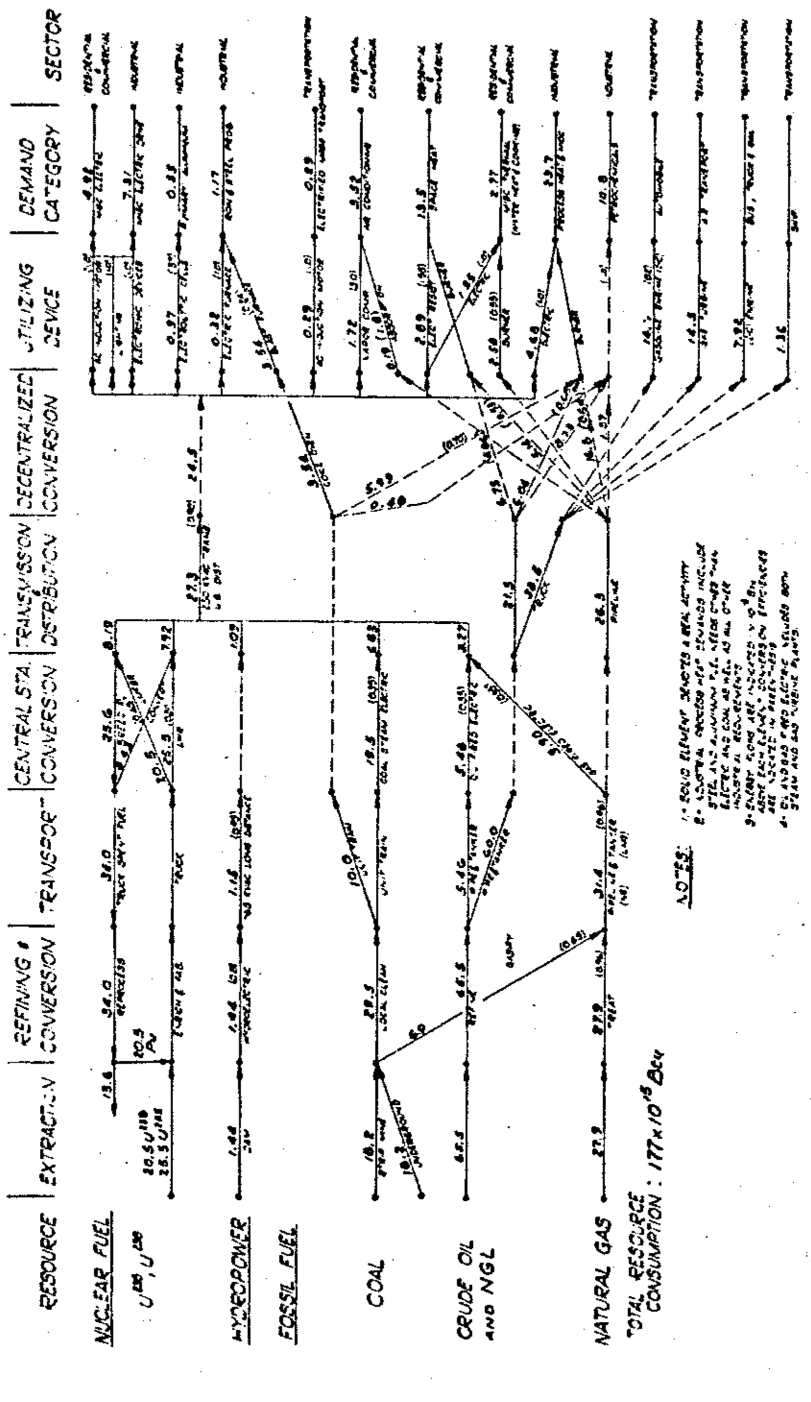
2. The use of hydrogen produced from coal as an alternate clean fuel in the transportation sector.

3. Energy transport and distribution from remote central station sites to urban areas via hydrogen in pipelines.

All these concepts could be implemented to a limited extent by 1985 provided the required research and development programs were actively pursued. However, for the purpose of evaluating their potential impact on the energy system, attention was directed toward the year 2000. It was assumed that by then the concepts could be implemented to almost any extent desired with a 15- to 20-year transition period in the intervening years. The extent to which hydrogen produced with off-peak power can be exploited is limited by the central station electric capacity and load factor forecast for the year 2000. The amount of hydrogen produced from coal in the second option is set at the same value as in the first concept so that the two cases may be conveniently compared. For the third concept, it is arbitrarily assumed that about 20% of the electrical energy production in the year 2000 requires long-distance transport of hydrogen from remote central station sites to urban load centers.

The basic technique employed in the analysis of these concepts makes use of "reference energy systems." This system is a flow-chart model in which projected energy demands, beginning with resource extraction and ending with sector utilization, may be specified and allocated. The year 2000 reference energy system is given in Fig. 12. Environment effects are measured in terms of fossil fuel and radioactive

REFERENCE ENERGY SYSTEM, YEAR 2000



emissions and are based upon emission factors given in Ref. 58.

6.1 Unit Energy Cost Comparisons

This analysis recognizes that electricity is a clean and convenient energy form to the user and will always fulfill a unique and necessary role in the energy system. The reference energy system for the year 2000 in Fig. 12 clearly shows that there are energy needs which can be best satisfied with general-purpose fuels. Thus, this analysis considers a variety of energy transmission schemes which can supply either hydrogen or electricity. Hydrogen can be used directly as a fuel or used in the manufacture of derivative fuels such as methanol or ammonia. Figure 13 illustrates schematically the three general types of energy delivery system alternatives which are considered.

Hydrogen and electricity are highly compatible energy forms which are interconvertible and have a great many end use applications. It is important to recognize that the overall cost of energy to the user depends on the ratio of the electrical to general purpose fuel energy requirements. At the present time, the ratio of electrical to general-purpose fuel energy delivered to all end uses in the energy system is approximately 1:10; in the reference year 2000 this ratio is projected to be approximately 1:4.

It should also be recognized that in the near term coal will be an important primary source of energy from which relatively inexpensive fuels, such as hydrogen, methanol, methane, and gasoline, can be derived. The availability of coal is an important factor in the early transition period from fossil to nuclear-derived synthetic fuels.

In this analysis the unit cost of energy delivered to the residential consumer has been estimated for a variety of energy delivery systems. The distinction between the cost of energy to residential customers and commercial or industrial users is assumed to be only in the cost of local distribution of the energy form (i.e., electricity or gaseous hydrogen, which are assumed to cost $\$2.55/10^6$ Btu and $\$0.66/10^6$ Btu,[58] respectively). The average cost of this service to an industrial

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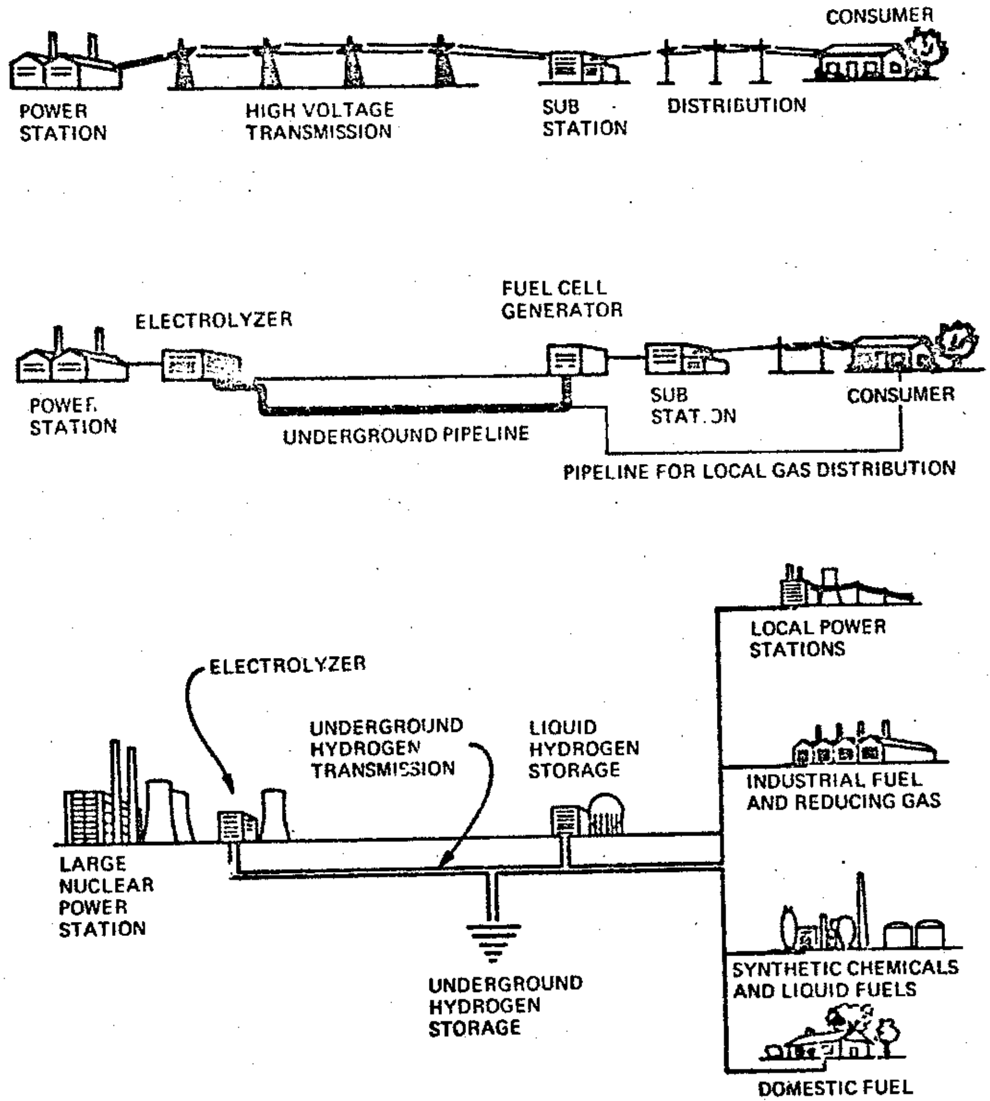


Conventional Power Delivery System (Above);
Underground Hydrogen Power Delivery System (Center)
Complete Hydrogen Energy Delivery System (Below)

or commercial customer is approximately one-third the above costs in most cases.

The energy delivery systems considered can be broken down into a number of separate unit costs such as primary fuel; production of electricity; production of hydrogen; storage, transmission, and conversion of hydrogen to electricity; and local distribution. It is assumed that the capital costs are amortized at 15% for 25 years. All the various separate process steps, including transmission and distribution, have some inefficiency associated with them which is considered in deriving the overall cost of the energy to the end use. The efficiencies assumed in deriving the cost of the energy delivered are as follows:

1. fuel conversion to electricity, 32%;
2. hydrogen production, 80%;
3. transmission of electricity and gas, 95%;
4. distribution of electricity and gas, 95%;
5. fuel cell conversion, 65%.

Table 11 is a breakdown of the various costs for five of the systems which have been considered. The nuclear-electric system uses a light-water reactor (LWR) to generate electricity in a central station operating with a plant factor of 0.5. The nuclear hydrogen system uses an LWR to produce hydrogen gas by means of an advanced electrolysis process achievable with research and development. In the third system the LWR generates hydrogen, which is transmitted to substations for conversion to electricity in a fuel cell and distributed in the conventional manner. The fourth system produces and delivers hydrogen using off-peak nuclear power. In this case only the fuel and operating cost of the plant and none of the capital costs are charged to the price of the electricity. The last column gives a breakdown of the cost of coal gasification in which the coal cost is assumed to be 29¢/10^6 Btu (~$7.50/ton).

Energy transmission schemes producing gaseous hydrogen which is transmitted by pipeline to a substation where all the hydrogen is reconverted to electricity have merit only under very special

Table 11. Cost breakdown ($10⁶) for some energy delivery systems supplying both electricity and hydrogen compared with a conventional all-electric system

	Nuclear electric[a]	Nuclear hydrogen[b]	Nuclear hydrogen conversion to electricity in fuel cell[c]	Off-peak nuclear hydrogen[d]	Coal-derived hydrogen[e]
Fuel	0.52	0.65	1.00	0.65	0.61
Electricity Production	3.69	2.80	4.30	0.21	0.61
Hydrogen production		0.31	0.48	0.84[f]	
Transmission 300 miles	0.13	0.10	0.10	0.10	0.10
Fuel cell conversion			1.25		
Distribution	2.55	0.66	2.55[h]	0.66	0.66
Total Delivered Cost	Electricity, 6.89 (23.5)[g]	Gas, 4.52	Electricity, 9.68 (33.0)[g]	Gas, 2.46	Gas, 1.98

[a]This is a conventional nuclear-electric system with a plant factor equal to 0.5.

[b]This system generates hydrogen gas with an advanced technology achievable with research and development. The plant factor for the electric plant is assumed to be 0.85 due to the better load characteristics of the hydrogen system.

[c]This system generates hydrogen and transports the gas to a fuel cell, where it is converted to electricity. Both the hydrogen production and fuel cell technologies are advanced systems achieved through research and development. The fuel cell system operates at 50% load factor.

[d]This system uses an advanced hydrogen production technology.

[e]The price of coal is assumed to be 29¢/10⁶ Btu, and the conversion efficiency .53%.

[f]This assumes that the plant factor is 0.3 compared with 0.95 in the other cases. The total cost of $2.46/10⁶ Btu is reduced to $1.94 when the electrolytic plant level factor is increased to 0.95.

[g]Equivalent cost in mills/kWhr.

[h]This value may be considerably lower depending on the nearness of the fuel cell installation to the electrical load.

conditions. In those circumstances where aboveground right of way is not available or is very expensive, underground transmission of hydrogen and reconversion to electricity may be an attractive alternative. It is estimated that underground electric transmission may be from 3 to 20 times more expensive than conventional aboveground electric transmission systems which could make underground hydrogen transmission and conversion to electricity an economic alternative. However, there are extra costs and inefficiencies in converting electricity to hydrogen and back to electricity. Under normal circumstances it is probably not realistic to consider such a system; however, when a significant fraction of the hydrogen transmitted can be used to supply nonelectrical needs (i.e., it can be used as a general purpose fuel for stationary or transportation applications), then the economics of hydrogen energy delivery schemes appear attractive.

The overall cost of energy delivered in a dual system delivering hydrogen and electricity compared with conventional systems is illustrated in Table 12. In this case it is assumed that 25% of the hydrogen produced is liquified for energy storage. The ratio of fuel to electric requirement is assumed to be 4:1 and fuel cells are used to supply the electrical needs. It is evident that a dual system delivering both electricity and hydrogen is competitive with an all-electric system. Using advanced hydrogen technology achievable with research and development the overall energy cost, that is, gas and electricity, is estimated to be $\$6.10/10^6$ Btu ($\sim$2¢/kWhr).

If presently available technology is used to implement such a system the cost would be $\$7.59/10^6$ Btu. These prices are almost competitive with the price of nuclear electricity from an LWR, which is shown in Table 12 to be in the range of $\$5.44$ to $\$6.89/10^6$ Btu.

In systems which deliver only electricity via hydrogen transmission and reconversion to electricity, the overall cost of the electricity will be high relative to the cost of electricity generated and delivered in a conventional manner. This point is illustrated in Table 13, which lists the estimated cost of electricity delivered in systems utilizing hydrogen transmission and reconversion in central stations with turbines

Table 12. Total cost of energy delivered in a dual system supplying both electricity and hydrogen compared with all-electric reference systems

	Cost ($\$/10^6$ Btu)	
	Advanced* Technology	Present Technology
Nuclear hydrogen with liquid storage delivering gas and electricity in the ratio of 4:1 where 25% of the hydrogen produced is liquefied and fuel cells supply the electrical requirements	6.10[a]	7.59
Nuclear, all-electric with a plant factor of 0.5	6.89	
Nuclear, all-electric with a plant factor of 0.85	5.44[b]	

[a]If none of the hydrogen is liquefied, the overall cost is reduced to $\$5.55/10^6$ Btu.

[b]Equivalent to a delivered cost of ~19 mills/kWhr. The production cost for this case was ~8 mills/kWhr.

*Advanced technology assumes about a factor of 3 reduction in initial cost of the water electrolysis and fuel cell equipment and an increase in the fuel cell efficiency from 50% to 65%.

Table 13. Cost of electricity delivered to residential consumers for some cases considered

	Cost ($\$/10^6$ Btu)	
	Advanced Technology	Present Technology
Off-peak nuclear electric	3.37	
Nuclear electric with plant factor = 0.85	5.44	
Nuclear electric with plant factor = 0.5	6.89	
Fossil-fueled electric with plant factor = 0.5	6.97	
Nuclear electric with pumped storage	9.48	
Nuclear hydrogen transmission and conversion to electricity in fuel cells	9.68	15.13
Nuclear hydrogen transmission and conversion to electricity in turbines	10.16	13.88
Nuclear hydrogen transmission and conversion to electricity in fuel cells where all the hydrogen is liquefied and stored prior to use	13.63	

or fuel cells using present or advanced technology achieved with research and development. It is clear that conventional electric systems are more economic; however, when such dual systems deliver hydrogen and electricity, the overall cost of the energy will be competitive with conventional all-electric systems, as illustrated in Table 12.

In addition to being able to satisfy the need for general-purpose fuels, coupling of electric generation and hydrogen production has the added advantage that hydrogen production and storability have the effect of improving the overall load factor of the electric generating system. Furthermore, a significant amount of storage capacity is available in the long distance transmission lines at low additional cost (see Sect. 4).

Table 14 lists the overall cost of hydrogen delivered to residential consumers using nuclear energy, nuclear energy with liquid hydrogen storage, off-peak nuclear energy, and hydrogen by coal gasification using presently available and advanced technology. It is evident that off-peak nuclear hydrogen and hydrogen derived from coal gasification are competitive. Further, it appears that the price of methane and hydrogen derived from coal gasification will be similar; thus more detailed studies are required to weigh the merits of hydrogen vs methane from coal.

6.2 Hydrogen for Peak Shaving

The elements of hydrogen production, liquefication, storage and reconversion to electricity can form the basis of an electric storage or peak shaving system. Using advanced technology achieved with research and development, such a system could be competitive with pumped storage costing $200/kW. In this system hydrogen (and oxygen) produced during off-peak periods in an electrolytic hydrogen plant operating at a plant factor of 0.3 is liquefied and stored. During the peak demand period the hydrogen (and oxygen) is converted to electricity in a turbine or fuel cell operating at a plant factor of 0.1. It is estimated that the

Table 14. Cost of hydrogen delivered to residential consumer for some cases considered

	Cost ($\$/10^6$ Btu)	
	Advanced Technology	Present Technology
Nuclear hydrogen	4.52	5.01
Nuclear hydrogen with liquid storage	7.23	7.82
Off-peak nuclear hydrogen[a]	2.47	4.05
Off-peak nuclear hydrogen where the electrolytic plant load factor is 0.95	1.93	2.42
Coal-derived hydrogen[b]	2.75	1.98

[a]This cost assumes that the hydrogen plant load factor is 0.3. Increasing the plant factor to 0.95 reduces the price of present and advanced technology to \$2.42 and $\$1.93/10^6$ Btu, respectively, as shown in case 4.

[b]Assuming the price of coal increases by a factor of 2.5.

electricity produced in such a system using present-day technology would cost approximately $\$23/10^6$ Btu for a system with turbine converters and approximately $\$31/10^6$ Btu using fuel cells. A research and development program which would reduce the cost of hydrogen production and increase the efficiency of turbines and fuel cells as well as reduce their cost could reduce the price of electricity derived in this type of system to approximately $\$12/10^6$ Btu. A comparison of these various costs are listed in Table 15, which shows that research and development could make peak shaving with hydrogen competitive with pumped storage costing in excess of $200/kW of installed capacity.[59]

The cost of peak shaving or electricity storage using hydrogen is high, primarily because of the inefficiencies of reconversion to electricity, the high cost of the conversion devices, and the relatively poor load factor of the hydrogen production plant and conversion devices. However, the technology required to implement this type of peak shaving system is available at the present time, but the cost of electricity would be a factor of 2 higher than achieved with pumped storage at $200/kW of installed capacity. If markets are available for nuclear-derived electrolytic hydrogen, it is more reasonable to build hydrogen production plants which can be used to supply electricity for short periods of time to meet peaking needs. The major fraction of the time, these plants would be operated to produce hydrogen which could be supplied for transportation residential or industrial applications. Thus the development of large-scale uses of electrolytic hydrogen and the necessary production facilities could have significant impact in supplying peak electrical demands.

6.3 Resource, Economic, and Environmental Perturbations for Hydrogen System Implementation

A summary of the essential resource, economic, and environmental perturbations associated with each implementation scheme for the utilization of hydrogen discussed in the previous section is given in Table 16. The first three implementation schemes, listed in Table 16

Table 15. Cost of electricity at the central station using hydrogen production, liquefication, and reconversion to electricity for peak shaving

	Cost ($\$/10^6$ Btu)	
	Advanced Technology	Present Technology
Hydrogen production and reconversion in fuel cells[a]	12	31
Hydrogen production and reconversion in turbines[b]	12	23
Pumped storage		11[c]
Central station electricity[d]		4

[a]The electrolytic cells are assumed to operate at a plant factor of 0.3, and the power cost is due only to the fuel and operation and maintenance costs of the electric plant.

[b]The plant factor for the turbine and fuel cell reconversion devices is assumed to be 0.1.

[c]It is assumed that the present cost of a pumped storage facility is $200/kW.

[d]The plant is assumed to be an LWR operating at a plant factor of 0.5.

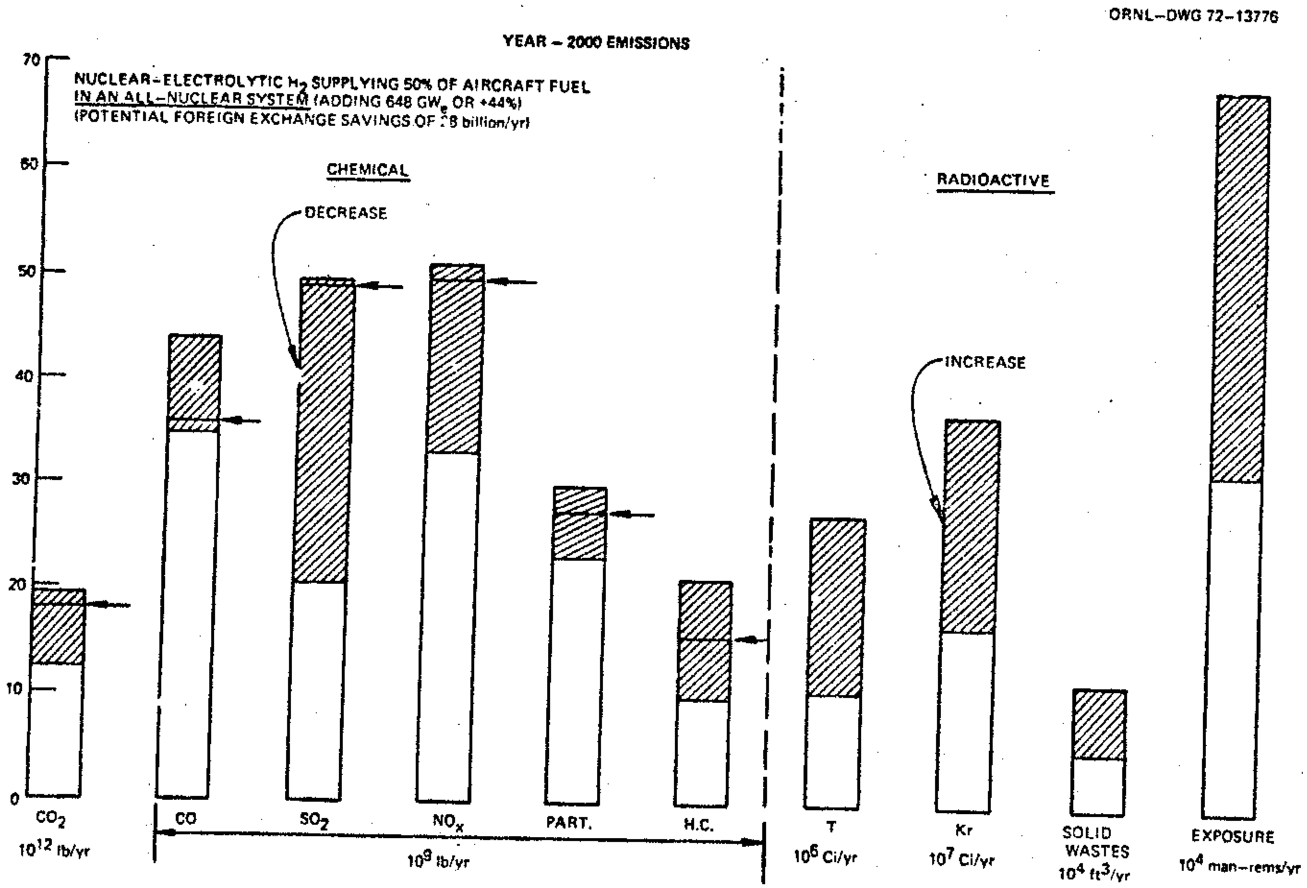
under the heading Perturbed Year 2000-I, -II, and -III, represent possible methods for the utilization of off-peak electric power. With the emphasis behind the search for alternative energy sources centered around (1) projected difficulties in providing an adequate petroleum supply and (2) growing requirements for stringent controls on the pollution of air from all energy sources, use of clean-burning hydrogen for transportation applications is given consideration here as an option.

The amount of available off-peak power in the year 2000 reference energy system can satisfy: (1) 50% of the automotive, or (2) 50% of the aircraft, or (3) all the diesel fuel requirements. The petroleum resource consumption decreases in each case, and under the all-nuclear scheme (year 2000-III), the greatest saving in petroleum resources is realized. This savings could substantially reduce reliance on foreign sources of petroleum, perhaps allowing a 15 to 20% decrease in the projected imports. The cost results show that, with exclusion of development costs of a portable hydrogen storage system suitable for use in ground transportation vehicles, the reference off-peak hydrogen case (2000-I) is directly competitive with gasoline. If the reference year 2000 electricity is all nuclear generated (2000-III), a substantial overall savings can be realized. This is due to the lower cost of nuclear fuels vs fossil fuels, along with the assumed exclusive future construction of nuclear-electric power plants, and the savings in crude oil and refining costs. The cost analysis considers automotive utilization exclusively.

Emissions in the transportation sector are shifted in each case from high-level concentrations in populated urban centers to central station electric sites, making them amenable to improved methods of power plant emissions control and providing a mechanism of dispersion that allows an acceptable overall level of air quality to be maintained. Although the year 2000-I case that uses offpeak electric power generated by the reference year fuel mix shows an overall increase in fossil-fuel emissions, these emissions are shifted away from urban concentrations. Assuming the reference projections for diesel utilization and the present uncontrolled emissions for these vehicles, replacement of diesel fuel with hydrogen gives the greatest overall reduction in fossil-fuel emissions, as is seen from the perturbed year 2000-I, -III diesel utilization emissions. The problems of making a quantitative evaluation of some of the trade-offs inherent in these comparisons is illustrated in Fig. 14. This figure shows the emissions occurring for Case 2000-III with 50% of the aircraft fuel being supplied by hydrogen. Chemical emissions are significantly reduced while radioactive materials are increased. It should be realized that the increased radiation exposure averaged over the population would be equivalent to only 1.5 to 3.5% of normal background radiation.

Following the off-peak electric implementation schemes, Table 16 lists the results for the gasification of coal into hydrogen (perturbed year 2000-IV), and, for comparison, methane is considered as an alternate fuel from coal (2000-V). The resource perturbations show an increase in coal consumption that is directly offset by the decrease in oil consumption, that is, the amount of oil consumption shown is exchanged for a larger (about 35%, due to conversion efficiencies in the gasification process) coal consumption. The cost numbers indicate that gasification is directly competitive with (1) gasoline as in the reference case, (2) the perturbed year 2000-I, and further, that no economic basis exists for a choice between hydrogen and methane. The primary environmental advantage of hydrogen from coal over the previous cases is the lack of radioactive emissions and the problems of radioactive waste disposal and storage. Methane, being a hydrocarbon fuel, is less desirable from an emissions standpoint, as can be seen by comparing the reductions of carbon monoxide possible with hydrogen.

The final section under perturbed year 2000-VI in Table 16 summarizes the GE-TEMPO scheme[60] in which hydrogen is used as a medium of energy transmission. Electrolytic hydrogen is generated at a remote nuclear central station electric site, piped underground to gas turbine substations, and used to fuel the turbines that generate electricity for local distribution. This scheme has merit only if conversion efficiencies (electrolysis, gas turbine) can be raised substantially,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YEAR – 2000 EMISSIONS
NUCLEAR-ELECTROLYTIC H_2 SUPPLYING 50% OF AIRCRAFT FUEL
IN AN ALL-NUCLEAR SYSTEM (ADDING 648 GW_e OR +44%)
(POTENTIAL FOREIGN EXCHANGE SAVINGS OF ?8 billion/yr)
CHEMICAL
DECREASE
RADIOACTIVE
INCREASE
0
10
20
30
40
50
60
70
CO_2
10^{12} lb/yr
CO
SO_2
NO_x
PART.
H.C.
10^9 lb/yr
T
10^6 Ci/yr
Kr
10^7 Ci/yr
SOLID WASTES
10^4 ft^3/yr
EXPOSURE
10^4 man-rems/yr

T-ble
Summary of Resour
Environmental Pertu
Reference Year Data :

	Reference Year 2000	Perturbed Year 2000-I: Reference Off Peak Generation of Hydrogen for Transportation Systems			Perturbed Year 2000-II: Reference Off-Peak Fossil Shifted to Base-Loaded Nuclear	Pert All-Nucl of Hydro
Annual Resource Consumption[1] (10^{15} BTU/yr)						
Coal[2]	36.4		+11.1		0	
Oil[3]	65.5		-4.7		-7.5	
Natural Gas	27.9		+2.6		0	
U^{235}	25.5		+5.87		+14.8	
U^{238}	20.5		+4.75		+12.0	
Totals:	175.8		+19.6		+19.3	
Annual Costs[4] (10^9 \$/yr)						
Capital Construction (Power plant, elect. H_2)	69.1		+6.2		+17.4	
Fuel (Power plant)[5]	13.6		+5.8		+3.1	
Fuel (Automobile)[6]	19.6		-9.8		-9.8	
Operation and Maintenance (Power plant, elect. H_2)	3.94		+1.9		+1.9	
Transmission (Gasoline, H_2)	2.35		-0.40		-0.48	
Local Distribution (Gasoline, H_2)	10.9		-0.55		-0.55	
Totals:			+3.07		+11.6	
Emissions and Wastes:[9]		Automotive Utilization (or)	Aircraft Utilization (or)	Diesel Utilization	Automotive Utilization	Automoti Utilizat
(a) Fossil fuel						
CO_2 (10^{12} lb/yr)	20.1	+2.11	+2.12	+1.96	-1.12	-6.89
CO (10^9 lb/yr)	43.4	-5.43	-7.56	-11.7	-5.87	-6.65
SO_2 (10^9 lb/yr)	51.1	+15.2	+14.9	+14.1	-0.30	-28.1
NO_x (10^9 lb/yr)	52.0	+9.0	+7.46	-10.3	0	-16.1
Particulates (10^9 lb/yr)	30.1	+1.87	-0.07	+1.68	-0.52	-4.77
Hydrocarbons (10^9 lb/yr)	15.8	-0.44	-5.00	-1.73	-0.7	-1.16
Aldehydes	0.837	+0.029	-0.128	-0.136	0	-0.053
(b) Radioactive						
T (10^6 Ci/yr)	12.43	+2.87	+2.87	+2.87	+7.37	+14.87
Kr (10^6 Ci/yr)	168.9	+38.8	+38.8	+38.8	+98.2	+202.4
Solid high level wastes (10^3 ft^3/yr)	54.0	+12.4	+12.4	+12.4	+31.6	+64.5
Population exposure (10^3 man-rems/yr)	318.0	+73.4	+73.4	+73.4	+186.1	+379.9

NOTES:
(1) Excluding hydropower.
(6) Includes refining cost.

A

Table 16
esource, Economic, and
Perturbations Including
Data for the Year 2000.

Perturbed Year 2000-III: -Nuclear Off-Peak Electric Generation Hydrogen for Transportation	Perturbed Year 2000-IV: Gasification of Coal to Hydrogen for Transportation Systems	Perturbed Year 2000-V: Gasification of Coal to Methane for Transportation Systems	Perturbed Year 2000-V Gas Turbine Electrici from Nuclear Hydroger
-26.4	+10.0	+11.4	-10.2
-13.0	-7.5	-7.5	-3.2
+0.6	0	0	-2.1
+30.6	0	0	+21.9
+24.5	0	0	+17.0
+16.3	+2.5	+3.9	+23.4
+7.4 (8)	+5.7	+6.2	+19.0
-2.0	+2.8	+3.3	-0.1
-9.8	-9.8	-9.8	--
+1.9	+0.6	+0.7	+1.9
-0.48	-0.48	-0.48	-2.5
-0.55	-0.55	-0.95	0 (7)
-3.53	-1.73	-1.03	+18.3

omotive ilization (or)	Aircraft Utilization (or)	Diesel Utilization	Automotive Utilization (or)	Diesel Utilization	Automotive Utilization (or)	Diesel Utilization	Central Station Electric Emissions
-6.89	-6.88	-7.04	+1.11	+0.96	+1.42	+1.21	-3.12
-6.65	-8.78	-12.9	-5.87	-12.15	0	-6.87	-0.416
-28.1	-28.4	-29.3	-0.30	-1.45	-0.3	-1.52	-15.0
-16.1	-17.6	-35.4	0	-19.33	0	-19.5	-8.12
-4.77	-6.7	-4.96	-0.52	-0.71	-0.39	-0.59	-2.27
-1.16	-5.72	-2.44	-0.70	-1.99	0	-1.38	-0.25
-0.053	-0.21	-0.218	--	-0.17	0	--	-0.03
14.87	+14.87	+14.87	0	0	0	0	+10.45
02.4	+202.4	+202.4	0	0	0	0	+141.5
64.5	+64.5	+64.5	0	0	0	0	+46.0
79.9	+379.9	+379.9	0	0	0	0	+265.9

B

since the resource and cost perturbations show substantial increases due primarily to the required capital construction costs for the additional power plants required to compensate for the conversion inefficiencies. Here, 20% of the year 2000 fossil fuel power generated (excluding peaking plants which were eliminated) was shifted to nuclear fuel, and it was also required that 20% of the year 2000 power generated be delivered via the GE-TEMPO scheme.

The systems analyses examples discussed above are limited in scope and serve as a preliminary or sample analysis. A more detailed analysis is required which will make realistic detailed assumptions about end use efficiency as well as appliance or vehicle costs used in hydrogen systems. Furthermore it is evident that realistic total costs for resource use and for emissions controls and effects need to be applied to make final judgments about the relative merits of the various cases studied.

Nevertheless, it seems clear that the use of coal and of nuclear off-peak power, although limited in extent, can provide a low-cost substitute natural gas, and that a nuclear-hydrogen system can be more economical than a nuclear-electric energy delivery system.

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APPENDIX

The following members of the study panel on nonfossil synthetic fuels and fuel cells, together with other contributors listed below, were responsible for the preparation of this report. The work was sponsored by the AEC under the cognizance of the Division of Reactor Development and Technology.

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